Final
Determination of Compliance

(New Source Review Document)

Blythe Energy Project
Blythe, California

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List of Abbreviations

ATCM	Airborne Toxic Control Measure
BACT	Best Available Control Technology
BEP	Blythe Energy Project
CARB	California Air Resources Board
CEC	California Energy Commission
CO	Carbon monoxide
CTG	Combustion turbine generator
FDOC	Final Determination of Compliance
HDPP	High Desert Power Project
HRA	Health Risk Assessment
HRSG	Heat recovery steam generator
LAER	Lowest Achievable Emission Rate
MACT	Maximum Achievable Control Technology
MDAQMD	Mojave Desert Air Quality Management District (District)
NO_2	Nitrogen dioxide
NO_x	Oxides of nitrogen
O_2	Molecular oxygen
PDOC	Preliminary Determination of Compliance
$PM_{2.5}$	Fine particulate, respirable fraction $\leq$ 2.5 microns in diameter
PM_{10}	Fine particulate, respirable fraction $\leq$ 10 microns in diameter
PSD	Prevention of Significant Deterioration
SCAQMD	South Coast Air Quality Management District
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SO_x	Oxides of sulfur
STG	Steam turbine generator
TOG	Total Organic Gases
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compounds

1. Introduction

The Mojave Desert Air Quality Management District (MDAQMD) received an Application for New Source Review for the Blythe Energy Project (BEP) from Wisvest Corporation dated January 7, 2000. The MDAQMD notified the applicant that this application was complete with a letter dated January 25, 2000.

The MDAQMD issued a Preliminary Determination of Compliance (PDOC) for the BEP on August 10, 2000. Minor comments were received regarding the PDOC, which have been addressed by the BEP and the District. This document represents the final new source review document, or Final Determination of Compliance (FDOC), for the proposed project.

As required by MDAQMD Rule 1306(E)(1)(a), this document will review the proposed project, evaluating worst-case or maximum air quality impacts, and establish control technology requirements and related air quality permit conditions. This document represents the preliminary pre-construction compliance review of the proposed project, to determine whether construction and operation of the proposed project will comply with all applicable MDAQMD rules and regulations.

2. Project Location

The BEP will be located on a 76 acre site five miles west of the City of Blythe, on two adjacent parcels bounded on the south by Hobsonway and on the east by Buck Boulevard. The project site is presently outside the incorporated area of the City of Blythe.

Site Description

The BEP site will include combustion turbine trains with exhaust stacks, heat recovery steam generator units, a steam turbine generator, a de-aerating surface condenser, cooling towers, water treatment, lined evaporation ponds, an emergency fire pump, transformers, and a 161 kV/230 kV high voltage switchyard. Natural gas will be delivered to the plant site boundary from one of two nearby high pressure (550 to 900 psig) natural gas transmission lines. If natural gas were obtained from the El Paso Natural Gas Company, an 11.5 mile pipeline would be constructed into Arizona. If natural gas were obtained from the Southern California Gas Company, a 0.8 mile pipeline would be constructed. Water will be obtained from underlying groundwater through on-site wells.

3. Description of Project

The BEP proposes to construct an electrical generating facility employing natural gas fired combined-cycle (combined Brayton and Rankine cycle) gas combustion turbine trains. The BEP is intended to sell electricity to the regional power pool and other consumers. The project will produce approximately 520 MW with an expected availability of 95 percent. Construction is scheduled to commence in 2000, with commercial operation scheduled to commence in 2002.

The project will have twin F Class Siemens V84.3A combustion turbine generators (CTGs) driving dedicated duct burner-equipped heat recovery steam generators (HRSGs). The CTGs and HRSG duct burners will be exclusively fueled by pipeline-quality natural gas, without back-up liquid fuel firing capability. The CTG power blocks each include a turbine air compressor section, gas combustion system combustors, power turbine, and a 60-hertz generator. Inlet air will be filtered and conditioned, with chilling supported by a mechanical draft wet cooling tower. Ambient air is filtered and compressed in a multiple-stage axial flow compressor. Compressed air and natural gas are mixed and combusted in the turbine combustion chamber. Lean pre-mix low NO_x combustors are used to minimize NO_x formation during combustion. Exhaust gas from the combustion chamber is expanded through a multi-stage power turbine which drives both the air compressor and the electric power generator. Heat from the exhaust gas is then recovered in a heat recovery steam generator (HRSG).

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation. A duct burner in each HRSG will provide supplementary firing during high ambient temperatures to maintain constant steam production to the condensing steam turbine generator (STG). A Selective Catalytic Reduction (SCR) system and sufficient space for a high temperature oxidation catalyst will be located within each HRSG. Steam will be produced in each HRSG and flow to the STG. The STG will drive an electric generator to produce electricity. STG exhaust steam will be condensed in a surface condenser with water from a mechanical draft wet cooling tower.

The project site will also be equipped with a 303 hp emergency diesel-fueled water pump.

Overall Project Emissions

The BEP will produce exhaust emissions during three basic performance modes: startup; operations mode; and shutdown. In addition to combustion related emissions, the project will have evaporative and entrained particulate emissions due to the operation of evaporative cooling towers. Turbine emissions estimates are based on manufacturer data. Operation at less than 70 percent load mode has been defined by BEP as transient operations, or startup/shutdown. The project is proposing the use of Siemens F Class V84.3A(2) turbines. Operational emissions are estimated by Siemens; transient emissions estimations are based on actual V84.3A(2) turbine transient data.[1]

Maximum Annual Emissions

Table one presents maximum annual facility operational emissions. Maximum annual NO_x and CO emissions are calculated by assuming ten cold starts, 50 warm starts, 100 hot starts, 160 shutdowns and 7564 hours of operation at the 59° F at 100 percent load hourly rate. Maximum annual VOC and PM_{10} emissions are calculated by assuming 8760 hours of operation at the 59° F at 100 percent load with duct burner hourly rate (PM_{10} front and back half emissions are estimated). Maximum annual SO_x emissions are calculated by assuming 8760 hours at the maximum fuel use rate (with duct burners) with a fuel sulfur content of 0.5 grains/100 scf and complete conversion of fuel sulfur to exhaust SO_x. The maximum annual cooling tower PM_{10}

[1] "Blythe Energy Project Air Emissions," Greystone Environmental Consultants, April 2000

emissions are calculated by assuming 8760 hours of operation and are included in the facility totals. Maximum total SO_x emissions are presented as 24 tpy, but an unknown fraction of these (fuel sulfur) emissions are accounted for in the PM_{10} emissions (as the PM_{10} estimate includes filterable and condensable particulate).

Table 1 – BEP Maximum Annual Operational Emissions					
	NO_x	**CO**	**VOC**	**SO_x**	**PM_{10}**
Tons per year	202	306	24	24	103

Maximum Daily Emissions

Table two presents maximum daily facility emissions calculated under worst case conditions. Maximum daily NO_x, VOC and CO emissions are calculated by assuming one cold start, five hot starts, six shutdowns and 11.9 hours of operation (20° F/100% load for NO_x and 95° F/100% load for CO and VOC). Maximum daily SO_x emissions are calculated by assuming 24 hours of operation at the maximum fuel use rate (with duct burners) with a fuel sulfur content of 0.5 grains/100 scf and complete conversion of fuel sulfur to exhaust SO_x. Maximum daily PM_{10} emissions are calculated by assuming 24 hours of operation at the 95° F at 100 percent load with duct burner hourly rate (PM_{10} front and back half emissions are estimated).

Table 2 – BEP Maximum Daily Operational Emissions					
	NOx	**CO**	**VOC**	**SO_x**	**PM_{10}**
Pounds per day	5762	3808	239	130	565

Equivalent Hourly Emission Rates

Table three presents maximum hourly emission rates for each turbine in operational mode. The cooling towers will emit a maximum of 0.546 pounds of PM_{10} per hour. Cooling tower emissions are not included in this table.

Table 3 - BEP Operational Mode Hourly Emission Rates (per turbine) All values in pounds per hour					
Mode	NO_x	CO	VOC	SO_x	PM_{10}
20° F at 100% load	19.8				
59° F at 100% load with duct burner	17.6	35.2	2.9		11.5
95° F at 100% load with duct burner		35.2	2.9	2.7	11.5

Initial Commissioning Period Emission Rates

The facility may exceed the maximum operational mode emissions during the initial commissioning period. Permit conditions limit these emissions to the maximum extent possible, but some emissions will occur without abatement. Table four presents the maximum emissions for the facility during the initial commissioning period, which will last no longer than 120 days. Maximum ambient impact for this increased level of emissions has been modeled using the existing BEP modeling methodology and assumptions, and these emission levels will not cause NO_2 or CO exceedances.[2] The increased annual emission limits will only apply to those twelve-month summaries which include any portion of the initial commissioning period.

Table 4 - BEP Initial Commissioning Period Facility Emission Rates (Maximum)			
Time Period	Units	NO_x	CO
Annual (rolling twelve month summary)	tons	273	421
Daily (calendar day)	pounds	22,000	44,000
Hourly	pounds	1000	2000

5. Control Technology Evaluation

Best Available Control Technology (BACT) is required for any new facility that emits, or has the potential to emit, 25 pounds per day or more or 25 tons per year or more of any non-attainment pollutant or its precursors (MDAQMD Rule 1303(A)). The proposed project site is non-attainment for ozone (state standard) and PM_{10} (state standard), and their precursors (NO_x, VOC, and SO_x). Based on the proposed project's maximum emissions as calculated in §4 above, each permit unit at the proposed BEP must be equipped with BACT/Lowest Achievable Emission Rate (LAER) for NO_x, VOC, PM_{10} and SO_x, and BACT for CO. Note that the proposed project site is attainment/unclassified for all federal ambient air quality standards; the project triggers BACT for CO, NO_2, VOC and PM through PSD review. The applicant has submitted a BACT analysis that evaluates the BACT and LAER for these pollutants, trace organics, and trace metals.[3]

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[2] "Supplemental Air Quality Information Submitted to the CEC for the BEP," Greystone Environmental Consultants, October 24, 2000

[3] "Blythe Energy, LLC Application for New Source Review," Wisvest Corporation, January 7, 2000

All concentration levels presented in the following BACT determinations are corrected to 15% oxygen, unless otherwise specified.

The District recently (June 29, 1999) determined BACT for a similar project (the High Desert Power Project (HDPP)) proposing essentially identical combined cycle gas turbines in Victorville.[4] This document will identify differences between the HDPP determination and the determination for the BEP. USEPA has made recommendations regarding BACT for combined cycle gas turbines,[5] and the CARB has published a guidance document that suggests BACT for power plants.[6] This determination will address both documents.

NO_x BACT

NO_x is a precursor of ozone and PM_{10}, and both ozone and PM_{10} are non-attainment pollutants at the proposed facility location. NO_x will be formed by the oxidation of atmospheric nitrogen during combustion within the gas turbine generating systems.

On June 12, 1998 the SCAQMD recognized a BACT guideline value of 2.5 ppm NO_x averaged over one hour for natural gas-fired turbines. Brooklyn Navy Yard Cogeneration Partners represents the most stringent gas turbine NO_x limit in the BACT/LAER clearinghouse at 3.5 ppm averaged over one hour. USEPA has identified an "achieved in practice" BACT value of 2.0 ppmv averaged over three hours (rolling) based on the recent performance of a Vernon, California natural gas-fired 32 megawatt combined cycle turbine (without duct burners) equipped with the patented SCONOX system. USEPA has accepted 2.5 ppmv averaged over a one hour as equivalent to the lower standard at the longer averaging time. CARB guidance suggests 2 ppmvd averaged over three hours or 2.5 ppmvd averaged over one hour as BACT. The BEP proposes 2.5 ppmvd averaged over a three hours as BACT. The District determined that 2.5 ppmvd averaged over one hour was BACT for the High Desert Power Project.

USEPA has asked that the NO_x control technologies referred to as SCONOX and XONON be specifically addressed in this BACT determination. BEP has performed additional analysis of the SCONOX technology, including a cost effectiveness comparison with the proposed low-NO_x burner and SCR system.[7] This supplemental analysis demonstrates a factor of three increase in cost associated with the SCONOX control technology, and addresses environmental and other impacts of both SCONOX and SCR control technologies. The District has established that the 2.5 ppmvd averaged over one hour limit is equivalent to the "achieved in practice" SCONOX performance. To date, SCONOX has not been determined to establish a lower achieved in practice NO_x emission concentration. XONON is an emerging internal catalyst technology. To date, XONON has publicized a demonstrated 2 ppmv NO_x emission concentration at Silicon Valley Power. The District considers 2.5 ppmvd averaged over one hour to be equivalent to this preliminary performance.

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[4] "Final Determination of Compliance, High Desert Power Project," MDAQMD, June 29, 1999

[5] Letter from M. Haber (USEPA Region IX) to C. Fryxell (MDAQMD), March 24, 2000

[6] "Guidance for Power Plant Siting and Best Available Control Technology," CARB Stationary Source Division, September 1999.

[7] "Supplemental BACT Analysis for Blythe Energy Prevention of Significant Deterioration Permit," Blythe Energy, October 3, 2000

The District therefore determines that a maximum NO_x concentration of 2.5 ppmvd averaged over one hour is acceptable as NO_x BACT for the BEP combined cycle gas turbines, achieved with low-NO_x burners and selective catalytic reduction in the presence of ammonia.

Ammonia Slip

Ammonia is a by-product of the SCR process, as some ammonia does not react and remains in the exhaust stream. As ammonia is not a regulated criteria air pollutant, but is a hazardous and toxic compound, the District will address the direct impacts of ammonia slip emissions as an element of the toxics and hazardous emissions analysis (§8). Since ammonia slip will be present at the proposed project site as a result of the proposed NO_x control technology, the District will also address ammonia as an adjunct to the NO_x BACT discussion.

CARB power plant guidance suggests "…Districts should consider establishing ammonia slip levels at or below 5 ppmvd at 15 percent oxygen."[8] The BEP proposed ammonia slip of 10 ppmvd as BACT. Recent SCR BACT ammonia slip determinations for similar power plants include: Elk Hills, 10 ppmvd averaged over 24 hours; Moss Landing, 10 ppmvd averaged over three hours; Delta, 10 ppmvd averaged over three hours; La Paloma, 10 ppmvd averaged over 24 hours; Pittsburg/Los Medanos, 10 ppmvd averaged over three hours; and Sutter, 10 ppmvd maximum. The District determined that an ammonia slip of 10 ppmvd averaged over three hours was BACT for the HDPP.

CO BACT

Carbon monoxide is formed as a result of incomplete combustion of fuel within the gas turbine generating systems. CO is an attainment pollutant at the proposed facility location.

On June 12, 1998 the SCAQMD recognized a BACT guideline value of 10 ppmvd CO (with no averaging time specified) for natural gas-fired turbines. Newark Bay Cogeneration Partners represents the most stringent gas turbine CO limit in the BACT/LAER clearinghouse at 1.8 ppmvd for a CO non-attainment area. CARB guidance suggests 6 ppmvd averaged over three hours as BACT. The District determined that a maximum CO concentration of 4 ppmvd averaged over twenty-four hours was BACT for the High Desert Power Project (with an oxidation catalyst optimized for VOC control). The BEP proposes 5 ppmvd at loads greater than 80 percent and 8.4 ppmvd at loads from 70 to 80 percent (and when duct-firing) averaged over three hours as a CO BACT emission limit through combustion controls.

The District therefore determines that a maximum CO concentration of 5 ppmvd (at loads greater than 80 percent) and 8.4 ppmvd (when duct-firing and at loads between 70 and 80 percent) averaged over three hours is acceptable as CO BACT for the BEP combined cycle gas turbines, achieved with combustion controls.

[8] CARB Power Plant Guidance, 12.

PM_{10} BACT

PM_{10} is a non-attainment pollutant at the proposed facility location. Particulate will be emitted by the gas turbine generating systems due to fuel sulfur, inert trace contaminants, mercaptans in the fuel, dust drawn in from the ambient air and particulate of carbon, metals worn from the equipment while in operation, and hydrocarbons resulting from incomplete combustion. Particulate will also be emitted by the cooling towers through evaporation and particulate mist entrainment.

Gas Turbines

There have not been any add-on particulate control systems developed for gas turbines from the promulgation of the first New Source Performance Standard for Stationary Turbines (40 CFR 60 Subpart GG, commencing with §60.330) in 1979 to the present. The cost of installing such a device has been and continues to be prohibitive and performance standards for particulate control of stationary gas turbines have not been proposed or promulgated by EPA.

The most stringent particulate control method for gas turbines is the use of low ash fuels such as natural gas. No add-on control technologies are listed in the EPA BACT/LAER Clearinghouse listing provided by the applicant. Combustion control and the use of low or zero ash fuel (such as natural gas) is the predominant control method listed for turbines with PM limits. CARB guidance suggests a requirement to burn natural gas with a fuel sulfur content not greater than 1 grain/100 scf is PM_{10} BACT. The District determined that sole use of natural gas as fuel was PM_{10} BACT for the High Desert Power Project. The BEP proposes the sole use of natural gas with a sulfur content not greater than 0.5 grains/100 scf as fuel as PM_{10} BACT.

The District therefore determines that the sole use of natural gas fuel with a fuel sulfur content not greater than 0.5 grain per 100 scf is acceptable as PM_{10} BACT for the combined cycle gas turbines.

Cooling Towers

The District determined the use of mist eliminators limiting drift to 0.0006 percent as PM_{10} BACT for the High Desert Power Project cooling towers. The applicant proposes mist eliminators as cooling tower BACT.

The District therefore determines that mist eliminators limiting drift to 0.0006 percent are acceptable as PM_{10} BACT for the BEP cooling towers.

SO_x BACT

SO_x is a precursor to PM_{10}, a non-attainment pollutant at the proposed facility location. SO_x is exclusively formed through the oxidation of sulfur present in the fuel.

The emission rate is a function of the efficiency of the source and the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_x. CARB guidance suggests that a requirement to burn natural gas with a fuel sulfur content not greater than 1 grain/100 scf is SO_x BACT. The District determined that sole use of natural gas with a fuel sulfur content not greater than 0.2 grains per 100 scf as fuel was SO_x BACT for the High Desert Power Project. The BEP proposes the sole use of natural gas with a sulfur content not greater than 0.5 grains/100 scf as fuel as PM_{10} BACT. Pipeline quality natural gas regulated by the California Public Utilities Commission typically must meet one grain per 100 scf. As was the case with the High Desert Power Project, the District will limit fuel sulfur content by permit condition.

The District determines that the exclusive use of natural gas fuel with no more than 0.5 grains of sulfur per 100 dry standard cubic feet is acceptable as SO_x BACT for the BEP combined cycle gas turbines.

VOC and Trace Organic BACT

VOC is a precursor for ozone and PM_{10}, which are non-attainment pollutants at the proposed facility location. VOCs and trace organics are emitted from natural gas-fired turbines as a result of incomplete combustion of fuel and trace organics contained in pipeline-quality natural gas.

The most stringent VOC control level for gas turbines has been achieved by those which employ catalytic oxidation for CO control. An oxidation catalyst designed to control CO would provide a side benefit of controlling VOC emissions. CARB guidance suggests that a 2 ppmvd averaged over three hours VOC emissions limit is VOC BACT. The District determined that a maximum VOC concentration of 1 ppmvd averaged over one hour was VOC BACT for the High Desert Power Project (achieved through the use of an oxidation catalyst optimized for VOC control). The BEP proposes a VOC emission limit of 2.0 ppmvd (2.6 ppmvd under duct firing) averaged over three hours as VOC BACT, achieved with combustion controls.

The District therefore determines that a maximum VOC concentration of 1 ppmvd averaged over one hour is acceptable as VOC and trace organic BACT for the BEP combined cycle gas turbines, achieved with combustion controls.

6. Class I Area Visibility Protection

The BEP evaluated the visibility reduction potential of project emissions on Prevention of Significant Deterioration (PSD) Class I areas. The MDAQMD approves of the visibility analysis methods and findings.

Findings

The BEP was estimated to generate a maximum 24-hour increase in the particle scattering coefficient of 3.28 percent, which is less than the significant change level of 5 percent.

Inputs and Methods

Visibility impacts were evaluated at the Joshua Tree National Monument (70 km from the proposed site), the only applicable site within 100 km. Meteorological data from a Southern California Edison station near the southwestern edge of Blythe for 1989 through 1993 was used for the analysis. Worst-case one hour emissions were used for the analysis. Visibility impacts were evaluated using the USEPA CALPUFF model.

7. Air Quality Impact Analysis

BEP performed the ambient air quality standard and Prevention of Significant Deterioration impact analyses for CO, PM_{10}, SO_2 and NO_2 emissions. The MDAQMD approves of the analysis methods used in these impact analyses and the findings of these impact analyses.

Findings

The impact analysis calculated a maximum BEP incremental increase for each pollutant for each applicable averaging period, as shown in Table Five below (note that maximum BEP impacts will be slightly higher during the initial conditioning period, but not in excess of any standard). When added to the maximum recent background concentration, the BEP did not exceed the most stringent (or lowest) standard for any pollutant. The BEP was estimated to consume a maximum NO_2 increment of 0.010 $\mu g/m^3$ in a PSD Class I area, which is less than the NO_2 increment threshold of 2.5 $\mu g/m^3$. The BEP was estimated to consume a maximum NO_2 increment of 0.47 $\mu g/m^3$ in a PSD Class II area, which is less than the overall NO_2 increment threshold of 25 $\mu g/m^3$.

Table 5 – BEP Worst Case Ambient Air Quality Impacts

Pollutant	Project Impact	Background	Total Impact	Federal Standard	State Standard
	All values in $\mu g/m^3$				
CO (1 hour)	1295	2280	3575	40000	23000
CO (8 hour)	345	1140	1485	10000	10000
PM_{10} (24 hour)	3.1	30	33	150	50
PM_{10} (annual)	0.4	15.9	16	50	30
SO_2 (3 hour)	1.4	10.4	12	1300	n/a
SO_2 (24 hour)	0.2	5.2	5	365	n/a
SO_2 (annual)	0.03	2.9	3	80	30
NO_2 (1 hour)	363	68	431	n/a	470
NO_2 (annual)	0.5	16.2	17	100	n/a
Maximum Initial Commissioning Period Impact					
CO (1 hour)	3271	2280	5551	40000	23000
CO (8 hour)	1214	1140	2354	10000	10000
NO_2 (1 hour)	400	68	468	n/a	470
NO_2 (annual)	1.0	16.2	17.2	100	n/a

Inputs and Methods

Worst case emissions were used as inputs, meaning 100 percent full load or mixed full load and startup for averaging times longer than one hour, and uncontrolled startup conditions for one hour averaging times. Data from a Southern California Edison site near Blythe for 1989 through 1993 was used as the meteorological inputs. Maximum ambient concentration data for 1993 through 1998 from the Twentynine Palms site was used for background concentrations. Mixing heights were determined from Desert Rock, Nevada data. For determining annual impacts, the conservative assumption of 100 percent conversion of NO_x to NO_2 was used.

The USEPA Industrial Source Complex Short Term (ISCST356) dispersion model was used to estimate ambient concentrations resulting from BEP emissions. The dispersion modeling was performed according to requirements stated in the Guideline on Air Quality Models (EPA-450/2-78-027R).

8. Health Risk Assessment

BEP performed a Health Risk Assessment (HRA) for carcinogenic, non-carcinogenic chronic, and non-carcinogenic acute toxic air contaminants. The MDAQMD approves of the HRA methods and findings.

Findings

The HRA calculated a peak 70-year cancer risk of 0.4 per million. The calculated peak 70-year residential cancer risk is less than 1.0 per million (for all receptors). The maximum non-cancer chronic and acute Hazard Indices are both less than the significance level of 1.0 (0.21 and 0.03, respectively).

Inputs and Methods

The BEP will emit toxic air contaminants as products of natural gas combustion, equipment wear, ammonia slip from the SCR systems, and cooling tower emissions. Combustion emissions were estimated using emission factors from SCAQMD and USEPA, and the California Air Toxics Emission Factors (CATEF) database. Ammonia slip was assumed to be 10 ppm in the stack exhaust. Cooling tower emissions were estimated using USEPA emission factors for evaporative emissions and engineering calculation for drift droplets.

The SCREEN3 dispersion model was used to estimate ambient concentrations of toxic air pollutants. The CAPCOA Assessment of Chemical Exposure for AB2588 Version 93288 (ACE2588) risk assessment model was used to estimate health risks due to exposure to emissions. Surface data from the Blythe SCE site (1989 through 1993) and upper air data from Desert Rock, Nevada were used as meteorological inputs.

9. Offset Requirements

MDAQMD Regulation XIII – *New Source Review* requires offsets for non-attainment pollutants and their precursors emitted by large, new sources. BEP has prepared and submitted a proposed offset package for the proposed project as required by Rule 1302(C)(3)(b).[9] The BEP is proposed for a location that has been designated non-attainment by CARB for ozone and PM_{10}. MDAQMD Rule 1303(B)(1) specifies offset threshold amounts for the non-attainment pollutant PM_{10}. MDAQMD Rule 1303(B)(1) also specifies offset threshold amounts for precursors of non-attainment pollutants: NO_x (precursor of ozone and PM_{10}), SO_x (precursor of PM_{10}), and VOC (precursor of ozone and PM_{10}). A new facility which emits or has the potential to emit more than these offset thresholds must obtain offsets equal to the facility's entire potential to emit. As Table Six shows, maximum BEP annual emissions exceed the offset thresholds for two

[9] "Offset Package for Blythe Energy Project," Greystone Environmental Consultants, June 14, 2000

of the four non-attainment pollutants and/or precursors. The table uses BEP maximum or worst-case annual emissions. The table also includes all applicable emissions, including the emissions increases from proposed new permit units (turbines, duct burners, SCR and wet cooling equipment), cargo carriers (none are proposed), fugitive emissions (none are proposed), and non-permitted equipment (none are proposed). For this analysis the MDAQMD assumes VOC is equivalent to ROC and SO_2 is equivalent to SO_x. Note that some fraction of sulfur compounds are included in both the SO_x and the PM_{10} totals, as the PM_{10} total includes front and back half particulate.

Table 6 - Comparison of BEP Emissions with Offset Thresholds
All emissions in tons per year

	NO_x	**VOC**	**SO_x**	**PM_{10}**
Offset Threshold	25	25	25	15
Maximum BEP Emissions	202	24	24	103

Required Offsets

MDAQMD Rule 1305 increases the amount of offsets required based on the location of the facility obtaining the offsets (on a pollutant category specific basis). As the BEP is located in two non-attainment areas, a state ozone non-attainment area and a state PM_{10} non-attainment area, the largest applicable offset ratio applies. Table Seven calculates the offsets required for the BEP.

Table 7 - Emission Offsets Required for the BEP
All emissions in tons per year

	NO_x	**PM_{10}**
Maximum BEP Emissions	202	103
Offset Ratio	1.0	1.0
Required Offsets	**202**	**103**

Identified Emission Reduction Credits

BEP has identified several sources of emission reduction credits (ERCs). BEP has purchased some or all credits from these sources. BEP has submitted sufficient information in advance of an actual ERC application for the local road paving projects to support the ERC numbers presented here. An application for ERCs from the paving of portions of Buck Boulevard and South Solano Street was received by the District on September 8, 2000. The proposed BEP ERC sources are summarized in Table Eight.

Table 8 - ERC Sources Identified by BEP
All emissions in tons per year

Source	**Location**	**VOC**	**PM_{10}**
International Light Metals Corporation	SCAQMD – AQ002663	15.3	
National Offsets, Inc.	SCAQMD – AQ002750	55.8	
National Offsets, Inc.	SCAQMD – AQ003056	18.1	
National Offsets, Inc.	SCAQMD – AQ003036	31.4	

Table 8 - ERC Sources Identified by BEP All emissions in tons per year			
Source	**Location**	**VOC**	**PM_{10}**
National Offsets, Inc.	SCAQMD – AQ003007	37.0	
Mobil Oil Corporation (Torrance, CA)	SCAQMD – AQ002698	63.9	
Ocean Air Environmental (Ventura, CA)	SCAQMD – AQ003052	30.7	
Pacific Texas Pipeline	SCAQMD – AQ000168	6.4	
National Offsets, Inc.	SCAQMD – AQ003052	64.6	
Buck Boulevard	MDAQMD (pending)		77.2
South Solano Street	MDAQMD (pending)		26.5
	Total ERCs Identified:	**323.2**	**103.7**

Emission Reduction Credits from Road Paving

CARB has commented negatively on the use of reductions generated by road paving projects to offset natural gas combustion emissions.[10] This position is based upon the relatively low concentration of fine particulate ($PM_{2.5}$ and $PM_{1.0}$) within unpaved road emissions as compared to the high concentration of fine particulate within products of natural gas combustion. The District can not support this position in the absence of ambient standards or other regulations that specifically control or regulate $PM_{2.5}$ and $PM_{1.0}$. This position would require the creation of a new class of credits for use as offsets: fine particulate credits. There is no ambient standard for fine particulate, nor are there any planning requirements for fine particulate. Existing Regulation XIII does not recognize $PM_{2.5}$ or $PM_{1.0}$ as regulated air pollutants, so the District can not require $PM_{2.5}$ or $PM_{1.0}$ offsets through the existing NSR process. Existing Regulation XIII specifically requires the use of consistent emissions as offsets, or PM_{10} offsets for new PM_{10} emissions, and only between PM_{10} and PM_{10} precursors on a case-by-case basis. In terms of total suspended particulate, the proposed road paving generates four times the gross reductions that would be generated by shutting down an equivalent combustion source (whose emissions are theoretically 100% fine particulate), generating an additional health and eliminated nuisance benefit. The District approved the use of road paving credits as offsets for the similar HDPP in 1999. The District supports the use of road paving PM_{10} reductions to offset natural gas combustion PM_{10} emissions within a PM_{10} non-attainment area.

Inter-District, Inter-Basin and Inter-Pollutant Offsetting

BEP has proposed to use inter-district, inter-air basin and inter-pollutant ERC trading to make up for the limited amount of ozone precursor ERCs available within the MDAQMD. The use of inter-district, inter-air basin and inter-pollutant offsets is specifically allowed for by Rule 1305(B)(4) through (6) (in consultation with CARB and USEPA, and in the case of inter-pollutant offsets, with the approval of USEPA). The MDAQMD Governing Board adopted a resolution approving the inter-district and inter-basin transfer of offsets from SCAQMD into the MDAQMD for the BEP on August 28, 2000. The identified SCAQMD offsets cannot be

[10] Letter from M. Kenny (CARB) to air pollution control officers, June 16, 2000 and letter from Menebroker (CARB) to Fryxell (MDAQMD), September 14, 2000.

transferred into the MDAQMD (or used within the MDAQMD) without a similar action by the SCAQMD Governing Board.

In the absence of approval of the proposed transfer by the SCAQMD Governing Board, the proposed project will be unable to commence construction. Note that the project has the flexibility to procure sufficient offsets within the MDAQMD from other sources in lieu of the SCAQMD offsets proposed for transfer into the MDAQMD, which would allow the project to commence construction (as long as the offsets are real, permanent, quantifiable, enforceable, and surplus as required by Regulation XIII).

BEP is proposing to use VOCs from the South Coast Air Basin within the jurisdiction of SCAQMD to offset NO_x emissions. The project site is approximately 130 miles from the South Coast Air Basin boundary. CARB guidance suggests a minimum inter-basin offset ratio of 6.0:1 for an offsetting distance of 130 miles (this is the absolute minimum ratio recommended by the guidance). The District cannot technically justify a ratio of this magnitude. An inter-pollutant VOC for NO_x ratio of 1.6:1 was required of the High Desert Power Project. The BEP is located in the same air basin as the HDPP (the Mojave Desert Air Basin). The BEP is essentially emitting the same pollutants as the HDPP.

The District therefore determines that this inter-district, inter-basin, and inter-pollutant trade is technically justified and will not cause or contribute to a violation of an ambient air quality standard. The District concludes that a VOC to NO_x ratio of 1.6:1 is acceptable for the VOC ERCs originating within the South Coast Air Basin for the BEP and is beneficial to both air districts. Table Nine summarizes the total offset requirements for the BEP.

Table 9 – Total BEP Offset Requirements
All values in tons per year

	NO_x	**PM_{10}**
Project Emissions	202	103
Local Offsets Identified	0	103.7
Inter-Pollutant Ratio (VOC for NO_x) and Inter-District Ratio	1.6	---
Required (Equivalent) VOC	323	---
Inter-District VOC Offsets Identified	323	---

10. Applicable Regulations and Compliance Analysis

Selected MDAQMD Rules and Regulations will apply to the proposed project:

Regulation II – Permits

Rule 221 – *Federal Operating Permit Requirements* requires certain facilities to obtain Federal Operating Permits. The proposed project will be required to submit an application for a federal operating permit within twelve months of the commencement of operations.

Regulation IV - Prohibitions

Rule 401 – *Visible Emissions* limits visible emissions opacity to less than 20 percent (or Ringelmann No. 1). During start up, visible emissions may exceed 20 percent opacity. However, emissions of this opacity are not expected to last three minutes or longer. In normal operating mode, visible emissions are not expected to exceed 20 percent opacity.

Rule 402 – *Nuisance* prohibits facility emissions that cause a public nuisance. The proposed turbine power train exhaust is not expected to generate a public nuisance due to the sole use of pipeline-quality natural gas as a fuel. In addition, due to the location of the proposed project, no nuisance complaints are expected.

Rule 403 – *Fugitive Dust* specifies requirements for controlling fugitive dust. The proposed project does not include any significant sources of fugitive dust so the proposed project is not expected to violate Rule 403.

Rule 403.2 – *Fugitive Dust Control for the Mojave Desert Planning Area* specifies requirements for construction projects. The construction of the proposed project will be required to comply with the requirements of Rule 403.2.

Rule 404 – *Particulate Matter – Concentration* specifies standards of emissions for particulate matter concentrations. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 404.

Rule 405 – *Solid Particulate Matter - Weight* limits particulate matter emissions from fuel combustion on a mass per unit combusted basis. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 405.

Rule 406 – *Specific Contaminants* limits sulfur dioxide emissions. The sole use of pipeline-quality natural gas as a fuel will keep proposed project emission levels in compliance with Rule 406.

Rule 408 – *Circumvention* prohibits hidden or secondary rule violations. The proposed project is not expected to violate Rule 408.

Rule 409 – *Combustion Contaminants* limits total particulate emissions on a density basis. The sole use of pipeline-quality natural gas a fuel will keep proposed project emission levels in compliance with Rule 409.

Rule 430 – *Breakdown Provisions* requires the reporting of breakdowns and excess emissions. The proposed project will be required to comply with Rule 430 by permit condition.

Rule 431 – *Sulfur Content in Fuels* limits sulfur content in gaseous, liquid and solid fuels. The sole use of pipeline-quality natural gas a fuel will keep the proposed project in compliance with Rule 431.

Rule 475 – *Electric Power Generating Equipment* limits NO_x and particulate matter emissions with mass rate and concentration standards. Permit conditions for the proposed project will establish limits which are in compliance with Rule 475.

Regulation IX – Standards of Performance for New Stationary Sources

Regulation IX includes by reference the New Source Performance Standard (NSPS) for gas turbines (40 CFR 60 Subpart GG, §§60.330 through 60.334). Permit conditions for the proposed project will establish limits which are in compliance with the gas turbine NSPS referenced in Regulation IX.

Regulation XII – Federal Operating Permits

Regulation XII contains requirements for sources which must have a federal operating permit and an acid rain permit. The proposed project will be required to submit applications for a federal operating permit and an acid rain permit by the appropriate date.

Regulation XIII – New Source Review

Rule 1300 – *General* ensures that Prevention of Significant Deterioration (PSD) requirements apply to all projects. The proposed project has submitted an application to the USEPA for an NO_2 and CO PSD permit, complying with Rule 1300.

Rule 1302 – *Procedure* requires certification of compliance with the Federal Clean Air Act, applicable implementation plans, and all applicable MDAQMD rules and regulations. The ATC application package for the proposed project includes sufficient documentation to comply with Rule 1302(D)(5)(b)(iii). Permit conditions for the proposed project will require compliance with Rule 1302(D)(5)(b)(iv).

Rule 1303 – *Requirements* requires BACT and offsets for selected large new sources. Permit conditions will limit the emissions from the proposed project to a level which has been defined as BACT for the proposed project, bringing the proposed project into compliance with Rule 1302(A). Prior to the commencement of construction the proposed project shall have obtained sufficient offsets to comply with Rule 1303(B)(1).

Rule 1306 – *Electric Energy Generating Facilities* places additional administrative requirements on projects involving approval by the California Energy Commission (CEC). The proposed project will not receive an ATC without CEC's approval of their Application for Certification, ensuring compliance with Rule 1306.

Maximum Achievable Control Technology Standards

Health & Safety Code §39658(b)(1) states that when USEPA adopts a standard for a toxic air contaminant pursuant to §112 of the Federal Clean Air Act (42 USC §7412), such standard becomes the Airborne Toxic Control Measure (ATCM) for the toxic air contaminant. Once an ATCM has been adopted it becomes enforceable by the MDAQMD 120 days after adoption or implementation (Health & Safety Code §39666(d)). USEPA has not to date adopted a Maximum Achievable Control Technology (MACT) standard that is applicable to the proposed project. Should USEPA adopt an applicable MACT in the future, the MDAQMD will be required to enforce said MACT as an ATCM on the proposed project. MACT is also required for each major source of toxic air contaminants. BEP will not emit more than ten tons of any individual toxic air contaminant, and will not collectively emit more than 25 tons of all toxic air contaminants, so MACT is not required.

11. Conclusion

The MDAQMD has reviewed the proposed project's Application for New Source Review and subsequent supplementary information. The MDAQMD has determined that the proposed project, after application of the permit conditions (including BACT requirements) given below, will comply with all applicable MDAQMD Rules and Regulations. This FDOC will be publicly noticed no later than October 20, including copies to USEPA, CARB and CEC. Written comments will be accepted for thirty days from the date of publication of the public notice. This FDOC will remain available for public inspection.

12. Permit Conditions

The following permit conditions will be placed on the Authorities to Construct for the project. Separate permits will be issued for each turbine power train. Separate permits will also be issued for each SCR system, duct burner, cooling tower and emergency fire pump. The electronic version of this document contains a set of conditions that are essentially identical for each of multiple pieces of equipment, differing only in District permit reference numbers. The signed FDOC has printed permits (with descriptions and conditions) in place of condition language listings.

Turbine Power Train Authority to Construct Conditions

[2 individual 1776 MMBtu/hr F Class Gas Turbine Generators,
Permit Numbers: B007953, B007954]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions) and GG (Standards of Performance for Stationary Gas Turbines). This equipment is also subject to the Prevention of Significant Deterioration (40 CFR 51.166) and Federal Acid Rain (Title IV) programs. Compliance with all applicable provisions of these regulations is required.

4. Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NO_x and VOC during periods of startup, shutdown and malfunction:
   a. Hourly rates, computed every 15 minutes, verified by CEMS and annual compliance tests:
      i. NO_x as NO_2 – 19.80 lb/hr (based on 2.5 ppmvd corrected to 15% O_2 and averaged over one hour)
      ii. CO – 35.20 lb/hr (based on 5.0 ppmvd (8.4 ppmvd with duct firing or when between 70 and 80 percent of full load) corrected to 15% O_2 and averaged over 3 hours)
      iii. Ammonia Slip – 10 ppmvd (corrected to 15% O_2 and averaged over three hours)
   b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
      i. VOC as CH_4 – 2.9 lb/hr (based on 1 ppmvd corrected to 15% O_2)
      ii. SO_x as SO_2 – 2.7 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
      iii. PM_{10} – 11.5 lb/hr

5. Emissions of CO and NO_x from this equipment shall only exceed the limits contained in Condition 4 during startup and shutdown periods as follows:
   a. Startup is defined as the period beginning with ignition and lasting until the equipment has reached operating permit limits. Cold startup is defined as a startup when the CTG has not been in operation during the preceding 48 hours. Hot startup is defined as a startup when the CTG has been in operation during the preceding 8 hours. Warm startup is defined as a startup that is not a hot or cold startup. Shutdown is defined as the period beginning with the lowering of equipment from base load and lasting until fuel flow is completely off and combustion has ceased.
   b. Transient conditions shall not exceed the following durations:
      i. Cold startup – 3.7 hours
      ii. Warm startup – 2.0 hours
      iii. Hot startup – 1.2 hours
      iv. Shutdown – 0.5 hour
   c. During a cold startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 376 lb
      ii. CO – 403 lb
   d. During a warm startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 278 lb
      ii. CO – 253 lb
   e. During a hot startup emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 260 lb
      ii. CO – 172 lb
   f. During a shutdown emissions shall not exceed the following, verified by CEMS:
      i. NO_x – 170 lb
      ii. CO – 48 lb

6. Emissions from this equipment, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:
   a. NO_x – 5762 lb/day, verified by CEMS
   b. CO – 3808 lb/day, verified by CEMS
   c. VOC as CH_4 – 239 lb/day, verified by compliance tests and hours of operation in mode
   d. SO_x as SO_2 – 130 lb/day, verified by fuel sulfur content and fuel use data
   e. PM_{10} – 565 lb/day, verified by compliance tests and hours of operation

7. Emissions from this facility, including the cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:
   a. NO_x – 202 tons/year, verified by CEMS
   b. CO – 306 tons/year, verified by CEMS
   c. VOC as CH_4 – 24 tons/year, verified by compliance tests and hours of operation in mode
   d. SO_x as SO_2 – 24 tons/year, verified by fuel sulfur content and fuel use data
   e. PM_{10} – 103 tons/year, verified by compliance tests and hours of operation

8. Particulate emissions from this equipment shall not exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.

9. This equipment shall exhaust through a stack at a minimum height of 130 feet.

10. The owner/operator (o/o) shall not operate this equipment after the initial commissioning period without the selective catalytic NO_x reduction system with valid District permit C007959 (or C007960) installed and fully functional.

11. The o/o shall provide stack sampling ports and platforms necessary to perform source tests required to verify compliance with District rules, regulations and permit conditions. The location of these ports and platforms shall be subject to District approval.

12. Emissions of NO_x, CO, oxygen and ammonia slip shall be monitored using a Continuous Emissions Monitoring System (CEMS). Turbine fuel consumption shall be monitored using a continuous monitoring system. Stack gas flow rate shall be monitored using either a Continuous Emission Rate Monitoring System (CERMS) meeting the requirements of 40 CFR Part 75 Appendix A or a stack flow rate calculation method. The operator shall install, calibrate, maintain, and operate these monitoring systems according to a District-approved monitoring plan and MDAQMD Rule 218, and they shall be installed prior to initial equipment startup. Six (6) months prior to installation the operator shall submit a monitoring plan for District review and approval.

13. The o/o shall conduct all required compliance/certification tests in accordance with a District-approved test plan. Thirty (30) days prior to the compliance/certification tests the operator shall provide a written test plan for District review and approval. Written notice

of the compliance/certification test shall be provided to the District ten (10) days prior to the tests so that an observer may be present. A written report with the results of such compliance/certification tests shall be submitted to the District within forty-five (45) days after testing.

14. The o/o shall perform the following annual compliance tests in accordance with the MDAQMD Compliance Test Procedural Manual. The test report shall be submitted to the District no later than six weeks prior to the expiration date of this permit. The following compliance tests are required:
    a. NO_x as NO_2 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 19 and 20).
    b. VOC as CH_4 in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Methods 25A and 18).
    c. SO_x as SO_2 in ppmvd at 15% O_2 and lb/hr.
    d. CO in ppmvd at 15% O_2 and lb/hr (measured per USEPA Reference Method 10).
    e. PM_{10} in mg/m^3 at 15% O_2 and lb/hr (measured per USEPA Reference Methods 5 and 202 or CARB Method 5).
    f. Flue gas flow rate in scfmd.
    g. Opacity (measured per USEPA reference Method 9).
    h. Ammonia slip in ppmvd at 15% O_2.

15. The o/o shall, at least as often as once every five years (commencing with the initial compliance test), include the following supplemental source tests in the annual compliance testing:
    a. Characterization of cold startup VOC emissions;
    b. Characterization of warm startup VOC emissions;
    c. Characterization of hot startup VOC emissions; and
    d. Characterization of shutdown VOC emissions.

16. Continuous monitoring systems shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:
    a. For NO_x, Performance Specification 2.
    b. For O_2, Performance Specification 3.
    c. For CO, Performance Specification 4.
    d. For stack gas flow rate, Performance Specification 6 (if CERMS is installed).
    e. For ammonia, a District approved procedure that is to be submitted by the o/o.

17. The o/o shall submit to the APCO and USEPA Region IX the following information for the preceding calendar quarter by January 30, April 30, July 30 and October 30 of each year this permit is in effect. Each January 30 submittal shall include a summary of the reported information for the previous year. This information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request:
    a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NO_x emission rate and ammonia slip.

b. Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, and hours in shutdown.
c. Date and time of the beginning and end of each startup and shutdown period.
d. Average plant operation schedule (hours per day, days per week, weeks per year).
e. All continuous emissions data reduced and reported in accordance with the District-approved CEMS protocol.
f. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NO_x, CO, PM_{10}, VOC and SO_x (including calculation protocol).
g. Fuel sulfur content (monthly laboratory analyses, monthly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by USEPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG)
h. A log of all excess emissions, including the information regarding malfunctions/breakdowns required by Rule 430.
i. Any permanent changes made in the plant process or production which would affect air pollutant emissions, and indicate when changes were made.
j. Any maintenance to any air pollutant control system (recorded on an as-performed basis).

18. The o/o must surrender to the District sufficient valid Emission Reduction Credits for this equipment before the start of construction of any part of the project for which this equipment is intended to be used. In accordance with Regulation XIII the operator shall obtain 202 tons of NO_x and 103 tons of PM_{10} offsets (VOC ERCs from SCAQMD may be substituted for NO_x ERCs at a rate of 1.6:1).

19. During an initial commissioning period of no more than 120 days, commencing with the first firing of fuel in this equipment, NO_x, CO, VOC and ammonia concentration limits shall not apply. The o/o shall minimize emissions of NO_x, CO, VOC and ammonia to the maximum extent possible during the initial commissioning period.

20. The o/o shall tune each CTG and HRSG to minimize emissions of criteria pollutants at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor.

21. The o/o shall install, adjust and operate each SCR system to minimize emissions of NO_x from the CTG and HRSG at the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor. The NO_x and ammonia concentration limits shall apply coincident with the steady state operation of the SCR systems.

22. The o/o shall submit a commissioning plan to the District and the CEC at least four weeks prior to the first firing of fuel in this equipment. The commissioning plan shall describe the procedures to be followed during the commissioning of the CTGs, HRSGs and steam turbine. The commissioning plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity.

The activities described shall include, but not be limited to, the timing of the dry low NO_x combustors, the installation and testing of the CEMS, and any activities requiring the firing of the CTGs and HRSGs without abatement by an SCR system.

23. The total number of firing hours of each CTG and HRSG without abatement of NO_x by the SCR shall not exceed 350 hours during the initial commissioning period. Such operation without NO_x abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place and operating. Upon completion of these activities, the o/o shall provide written notice to the District and CEC and the unused balance of the unabated firing hours shall expire.

24. During a period that includes a portion of the initial commissioning period, emissions from this facility shall not exceed the following emission limits (verified by CEMS):
a. CO – 421 tons/year (rolling 12 month summary), 44,000 pounds/calendar day and 2000 pounds/hour

25. During a period that includes a portion of the initial commissioning period, prior to the steady state operation of the SCR system, emissions from this facility shall not exceed the following emission limits (verified by CEMS):
b. NO_x – 273 tons/year (rolling 12 month summary), 22,000 pounds/calendar day and 1000 pounds/hour

26. Within 60 days after achieving the maximum firing rate at which the facility will be operated, but not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation at 100% load in compliance with the emission limits in Condition 4.

27. The initial compliance test shall include tests for the following. The results of the initial compliance test shall be used to prepare a supplemental health risk analysis:
    a. Formaldehyde;
    b. Certification of CEMS and CERMS (or stack gas flow calculation method) at 100% load, startup modes and shutdown mode;
    c. Characterization of cold startup VOC emissions;
    d. Characterization of warm startup VOC emissions;
    e. Characterization of hot startup VOC emissions; and
    f. Characterization of shutdown VOC emissions.

28. The o/o shall provide sufficient space and appurtenances within the Heat Recovery Steam Generator to allow the subsequent installation of a high temperature oxidation catalyst. A high temperature oxidation catalyst shall be installed if any VOC or CO limit specified by the above conditions is violated.

Duct Burner Authority to Construct Conditions

[2 individual 120 MMBtu/hr Natural Gas Duct Burners,

Permit Numbers: B007954, B007955]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be exclusively fueled with natural gas and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The duct burner shall not be operated unless the combustion turbine generator with valid District permit B007953 (or B007954), selective catalytic NO_x reduction system with valid District permit C007959 (or C007960), and oxidation catalyst (if installed) are in operation.

4. Fuel use by this equipment shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

Selective Catalytic NO_x Reduction System Authority to Construct Conditions

[2 individual SCR systems, Permit Numbers: tbd]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. This equipment shall be operated concurrently with the combustion turbine generator with valid MDAQMD permit B007953 (or B007954).

4. Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded 550° Fahrenheit. Except during periods of startup and shutdown, ammonia slip shall not exceed 10 ppmvd (corrected to 15% O_2), averaged over three hours.

5. Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of five (5) years and shall be provided to MDAQMD personnel on request.

Cooling Tower Authority to Construct Conditions

[2 individual Cooling Towers, Permit Numbers: tbd]

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

3. The drift rate shall not exceed 0.0006 percent with a maximum circulation rate of 146,000 gallons per minute (gpm) for the Main Cooling Tower and 22,000 gpm for the Chiller Cooling Tower. The maximum hourly PM_{10} emission rate shall not exceed 0.546 pounds per hour from both cooling towers, as calculated per the written District-approved protocol.

4. The operator shall perform weekly tests of the blow-down water quality. The operator shall maintain a log which contains the date and result of each blow-down water quality test, and the resulting mass emission rate. This log shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

5. The operator shall conduct all required cooling tower water quality tests in accordance with a District-approved test and emissions calculation protocol. Thirty (30) days prior to the first such test the operator shall provide a written test and emissions calculation protocol for District review and approval.

6. A maintenance procedure shall be established that states how often and what procedures will be used to ensure the integrity of the drift eliminators. This procedure shall be submitted to the District for approval at least thirty (30) days prior to construction and shall be kept on-site and available to District personnel on request.

Emergency Fire Pump Authority to Construct Conditions

[One Emergency Diesel IC Engine, Permit Number: tbd]

1. Operation of this equipment shall be conducted in accordance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.

3. This unit shall be limited to use for emergency fire fighting, and as part of a testing program that does not exceed 60 minutes of testing operation per week.

4. The owner/operator (o/o) shall use only diesel fuel whose sulfur concentration is less than or equal to 0.05% on a weight per weight basis in this unit.

5. The o/o shall maintain a log for this unit, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of five (5) years and shall be provided to District personnel on request:
   a. Date of each use or test;
   b. Duration of each test, in minutes;

c. Fuel consumed during each calendar year, in gallons; and
d. Fuel sulfur concentration (the o/o may use the supplier’s certification of sulfur content if it is maintained as part of this log).